



PUBLIC UTILITIES
COMMISSION

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Belize
Central America

PUC/ES/B3/2008

26th June 2008

Mr. Lynn Young
President and Chief Executive Officer
Belize Electricity Limited
2 ½ Miles Northern Highway
Belize City

Dear Mr. Young,

In accordance with the Electricity (Tariffs, Charges and Quality of Service Standards) Byelaws, 2005, S.I. No. 145 of 2005, Byelaw No. 33, kindly find enclosed the Final Decision of the Public Utilities Commission in the 2008 Annual Review Proceeding for Belize Electricity Limited.

Sincerely
PUBLIC UTILITIES COMMISSION

Mr. John Avery
Chairman

Enc.



PUBLIC UTILITIES
COMMISSION

Final DECISION

for the

ANNUAL REVIEW PROCEEDING 2008

for

Belize Electricity Limited

June 26, 2008

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1. Legal Framework

The Public Utilities Commission (PUC) is authorized under the Public Utilities Commission Act (No. 39 of 1999) to serve as the economic regulator for the electricity, water and telecommunications sectors in Belize.

The primary duty of the PUC is to ensure that the services rendered by public utility providers in all three sectors are satisfactory and that the charges imposed in respect of those services are reasonable. The PUC has the power to determine and prescribe rates that may be charged in respect of utility services and the standards which must be maintained in relation to such services. In addition, the PUC is responsible for the award of licenses and for monitoring and enforcing compliance with license conditions.

Sector specific legislation provides the legal framework for the PUC to carry out its duties and functions in a particular utility sector, as obtains in the regulation of the electricity sector, the Electricity Act (No. 13 of 1992), (the "Act"), as amended by Act (No. 40 of 1999) and Act (No. 12 of 2007) and the Electricity (Tariffs, Charges and Quality of Service Standards) Byelaws, 2005 (the "Byelaws"). The Byelaws govern the tariffs, rates, charges and fees for the transmission and supply of electricity and for existing and new services to be charged by a licensee to consumers in Belize, and the mechanisms, formulas, and procedures whereby such tariffs, rates, charges and fees shall be calculated and determined for all purposes. They also govern the quality of service standards (service reliability) for existing and new services at any time provided or to be provided by a licensee, and the mechanisms, formulas and procedures whereby such services shall be calculated and determined for all purposes. Further, the Byelaws reference the methodology used for Review Proceedings.

2. Methodology

The 2005 First Schedule (Rate Setting Methodology (RSM)) approved by the Commission in the Final Decision FTRP 2005 has been the subject of objections by BEL as well as by the Independent Expert for ARP 2007 and the Independent Expert for ARP 2008. It has also been the subject of concern by the Commission, and hence the First Schedule of FTRP 2005 has been amended in this ARP 2008. (See Decision 1 the First Schedule Amended)

3. Annual Review Proceedings

The Annual Review Proceedings (ARP) for the Annual Tariff Period (ATP) July 1, 2008 to June 30, 2009 commenced on April 2, 2008 upon the submission by Belize Electricity Limited (BEL) to the PUC requesting the PUC's approval of proposed regulated values, mean electricity rates, tariffs, charges and fees for the period July 1, 2008 to June 30, 2009.

Summary of BEL Submission

The submission made by BEL contained the following key points:

- Increase the Reference Price of Power from \$0.253 to \$0.287
- The Rate Stabilisation Account (RSA) recovery rate was proposed to increase from \$0.02 to \$0.045.
- The Value Added of Delivery was proposed to remain the same at \$0.168/kWh.
- The Mean Electricity Rate (MER) for July 1, 2008 to June 30, 2009 was proposed to increase from \$0.441/kWh to \$0.50.

- Tariffs were proposed to be changed as follows:

Annual Tariff Review Proceeding		
Tariff Class	Current Tariff	Proposed Tariff
Social		
Flat Rate	\$ 4.00	\$ 4.00
0000 - 0050 kWh (minimum \$4.00)	\$ 0.26	\$ 0.318
Residential (Include small commercial less than 2,500 kWh/month)		
Flat Rate	\$ 5.00	\$ 5.00
0000 - 0050 kWh	\$ 0.35	\$ 0.408
0051 - 0200 kWh	\$ 0.44	\$ 0.498
Above 0200 kWh	\$ 0.47	\$ 0.528
Commercial (Commercial greater than 2,500 kWh/month)		
Service Charge	\$100.00	\$100.00
00,000 - 10,000kWh	\$ 0.45	\$ 0.508
10,000 - 20,000 kWh	\$ 0.44	\$ 0.498
Above 20,000 kWh	\$ 0.43	\$ 0.488
Industrial 1 (Using greater than 30,000 kWh/month)		
Service Charge	\$100.00	\$100.00
Demand Charge per kVA/month	\$ 35.00	\$ 35.00
Off - peak energy	\$ 0.33	\$ 0.388
Peak energy (6 p.m. 9 p.m. Mon to Fri)	\$ 0.33	\$ 0.388
Industrial 2 (Avg Peak Load of 1.5 MW & greater)		
Service Charge	\$100.00	\$100.00
Demand Charge per kVA/month	\$ 21.00	\$ 21.00
Off - peak energy	\$ 0.28	\$ 0.338
Peak energy (6 p.m. 9 p.m. Mon to Fri)	\$ 0.28	\$ 0.338
Street Lighting	\$ 0.55	\$ 0.608

3.1 Comments

Three hundred and fifty interested parties sent comments in writing to the Public Utilities Commission (PUC) on BEL's submission in the ongoing Annual Review Proceeding (ARP).

The comments were received from members of the general public, as well as eight businesses including three hotels, two hundred members of the Orange Walk Business Association, National Fishermen Producers Cooperative Society Ltd, Succotz Village Council, Maya Leaders Alliance of Southern Belize, Toledo Institute for Development and Environment, the Peoples' National Party and the Peoples' United Party.

All comments received asked the PUC to deny the increase requested by BEL. One interested party suggested a smaller increase of 5% in this time of austerity.

Justification for the objections ranged as follows:

- Net profits and the cost of living and production make it unconscionable to grant such an increase. It will affect struggling families and stifle economic and social growth, and the country's development.
- The cooperative said its electricity bill is \$23,000 per month which makes the electricity component of producing a pound of seafood \$0.43. In other countries electricity cost is \$0.25 per lb. A rise in rates will make production cost too high, cutting into the cooperative's competitive edge.
- Electricity cost is highest operating expense in many businesses and the increase will have harmful effects on both the businesses and consumers.
- Belizeans have been forced to resort to austerity measures due to the rising cost of living and BEL must take a look at its bottom line and decide that a reduction in profits is the acceptable thing to do.

- Rates are unreasonable, resulting in high profits.
- Belizeans cannot afford an increase.
- BEL provides no acceptable justification for passing on increased expenses to the public. It is an insult to tell Belizeans that investors need a return in the face of the difficult economic times.
- All should sacrifice until the hard time passes.
- BEL's accounting practices hide a lot.
- It is in the best interest of the public.
- PUC must prevent exploitation by a monopoly and protect the local economy. We cannot sacrifice the society for continual growth capitalism of a foreign corporation.
- Value added element of taxes and business costs and 10% guaranteed profit need to be dissolved to make BEL operate on a normal business level. Profits should be capped at \$20 million with earnings above applied to rate reduction.
- Turbine is wasteful and unnecessary. The guaranteed ROR discourages normal commercial situation and economy resulting in excessive head counts, salaries and management fees.

During the proceedings, the PUC engaged BEL in responding to queries on the application and providing additional data as required.

The PUC is required to deliver an Initial Decision within thirty days of BEL's submission, establishing May 2, 2008 as the deadline for this Initial Decision.

3.2 Initial Decision

The PUC with the authority given under the Byelaws read along with other governing legislation rendered the following initial decisions:

Decision 1: Rate Setting Methodology

The PUC HEREBY APPROVES the amended First Schedule (Rate Setting Methodology) attached as ANNEX 1.

Decision 2: Reference Price of Power

The PUC HEREBY APPROVES a revised reference price of power (sales) of \$0.307 per kilowatt hour.

Decision 3: Cost of Power Rate Stabilization Account (CPRSA) Recovery

The PUC HEREBY APPROVES a Rate Stabilization Account recovery rate of \$0.004 per kilowatt hour.

Decision 4: Value Added of Delivery (VAD)

The PUC HEREBY APPROVES a Value Added of Delivery of \$0.13 per kilowatt hour.

Decision 5: Mean Electricity Rate

The PUC HEREBY APPROVES a Mean Electricity Rate (MER) of \$0.441 per kilowatt-hour resulting from the decisions made in Decision 2, Decision 3 and Decision 4 above, set for the Annual Tariff Period (ATP) July 1, 2008 to June 30, 2009.

The MER was calculated as follows:

		Regulated Values		
		ARP 2007 Final Decision 2006/07	ARP 2008 Adjustments	ARP 2008 Initial Decision 2008/09
Regulated Parameters				
Unit Cost of Power (sales)	\$/kWh	0.253	+0.054	0.307
Value Added of Delivery	\$/kWh	0.168	-0.038	0.130
Cost of Power Rate Stabilisation Account Adjustment	\$/kWh	0.02	-0.016	0.004
Mean Electricity Rate	\$/kWh	0.441	\$0.00	0.441

3.3 Objections to Initial Decision

Following the release of the Initial Decision, the Licensee and interested parties had a period of ten (10) days to file with the Commission, written comments on the decision. The Licensee (BEL) was the only entity to file objections.

BEL objections are listed as follows:

1. In its decision on Threshold Event Review Proceeding of March 28, 2008, the Public Utilities Commission (PUC) decided not to amend the cost of power component of the rates even though the bylaws of 2005 and the bylaws as amended in 2007 clearly required the PUC to adjust the cost of power component of the rates. The reasons given by the PUC were unrelated to the issue of rising cost of power and the refusal to comply with the law is causing the company to not meet one of the conditionality of its Scotia Bank Facilities - forecasted Cash Flow Coverage Ratio. The ARP decision also puts the company in violation of a key financial covenant with the Caribbean Development Bank (CDB) and the International Bank for Reconstruction and Development (IBRD) relating to loans that were lent to the Government of Belize and on-lent to BEL. Under these loans, the Company cannot borrow any money without the approval of the CDB and the IBRD once in violation of the covenants. (See list of covenants and letter to CDB in attachment A)
2. The earlier TERP and the 2008 ARP were based on the Energy Information Administration (EIA), www.eia.doe.gov, forecast of approximately US\$95 per barrel for West Texas Intermediate (WTI) crude in 2008. Since then, the EIA has increased its forecast for 2008 to over \$110 per barrel (see graph in attachment B). As of May 9, 2008 the price of oil has surpassed US\$126 per barrel and the price of firm power from CFE has increased to BZ\$362 per MWh. Based on these latest forecasts, the Wholesale Cost of Power in 2008 will significantly exceed the value in BEL's submission, and will even exceed the PUC's determination. The company's cash flows are even more strained than projected and it is very likely that another threshold event will be triggered shortly after the implementation of the Final 2008 decision.

3. The bylaws as amended in 2007 were repealed on March 28, 2008, four (4) days before the submission of the Annual Rate Proceeding was due with no consultation or advance notice. There was insufficient time for the company to redo its submission in accordance with the 2005 bylaws which required that the RSA balance be zeroed by the end of the Full Tariff Period which according to the 2005 bylaws ends on June 30th, 2009.
4. The Company carried out various actions and reported its financial results for 2007 on the basis of the 2007 bylaws which were in effect at the time. "Repealing the Bylaws does not retroactively change established financial positions and approved actions taken by the company such as the balance in the Rate Stabilization Account, the Regulated Asset Value, and the approval of Power Purchase Agreements. These were reported on and acted upon in accordance with the prevailing law".
5. The repeal of the 2007 bylaws leaves us with no legally authorized Rate Setting Methodology as the Rate Setting Methodology (RSM) which was introduced after the company had submitted its submission for the Full Tariff Review in 2005, and to which the company objected, was not promulgated by law. BEL has challenged the legality of the 2005 methodology.
6. A new RSM has again been introduced in the 2008 ARP after the company made its rate submission. This new RSM is being applied historically to calendar year 2007 and prior years, reversing previous decisions and agreements that dictated the historical results of the company's operations and set the stage for how the Utility operated in the most recent calendar year.
7. The new RSM has been introduced to justify the 2008 decision and yet again, it has been introduced without any genuine consultation with the utility as required by law (as, documented in our letter dated April 21, 2008). The repeal of the December 2007 RSM that was incorporated in the December 2007 amendments to the tariff byelaws (SI No. 141 of 2007) effectively means that there is no legally authorized RSM in place. The importance of having the RSM properly promulgated by law is manifest given the repeated attempts to change the rules with retroactive effect during the review process.

8. This pattern of arbitrarily changing the methodology, retroactively changing past decisions, refusing to honor past agreements and ignoring the requirements of the bylaws makes it impossible for the utility to rely on the tariff setting regulations or the decisions of the PUC. This of itself makes it impossible for the company to finance its operations. The company's past financial results cannot be relied upon, nor can the company make any commitments with respect to any financial covenant even when operating as a well managed utility. The bylaws of 2007 which included the only legally approved RSM should be re-instated and the 2008 ARP should be in accordance with that bylaw. Modification of the 2007 bylaw and the RSM should only be undertaken after due consultation with all stakeholders and proper consideration of the effect of changes on the industry.
9. One of the key principles enshrined in the Electricity Act is that the Utility must be allowed to earn a fair return. The Central Bank's average annual interest rate on low-risk 90-day deposits in 2007 was 8.4%. This would suggest that BEL's return should be in the range of 15%. The company's return on assets net of contributed capital in 2007 was 10.3%. In a public statement, the Chairman of the PUC explained that the 2008 decision lowered the allowed return to 8.5%. This rate of return on regulated assets is not in accordance with the very RSM supposedly being followed by the PUC. The rate of return in the RSM is a target of 12% with a range of 10% to 15%. The RSM also states that the return is a regulated value which can only be changed during an FTRP. The recent decision to reduce the return is therefore contrary to the rules of the 2005 and the 2008 RSM's.
10. Benchmark studies submitted to the PUC shows that the company is one of the most efficient when compared to similar sized utilities. Excluding cost of power, the company has reduced its operating cost per customer by 17% and its operating cost per megawatt hour by 32% over the last eight years. Yet, its return is low when compared to similar sized utilities in other jurisdictions (see attachment C).
11. The original RSM introduced in 2005 set out that the utility's total return would be evaluated every four years (the FTP) with any adjustments applied to the first ATP of the subsequent FTP. This gives the utility a window in which to operate efficiently for the benefit of consumers and its

investors. The recently introduced RSM now adjusts the Utility's revenues annually for variances in total return (Sections 19(d) and 78 violating this principle.

12. The 2008 RSM that was developed during the tariff review and used by the PUC now gives the PUC the right to penalize the company for having exceeded targeted operating expenses (Opex) in a given year by including a penalty in the next Annual Tariff Period (ATP). This is clearly an erroneous position. In the year that the Opex target is exceeded the utilities profits/returns would have been reduced in that year and penalizing the company in the subsequent ATP for this same variance doubles the impact of exceeding target opex on utility profits/returns. The same occurs in the reverse. Additionally this same section 51 of the 2008 RSM states in Note 4 to the section that the utility is not to be penalized for Opex performance above the target (Opex variance less than zero). There is an obvious inconsistency in the 2008 RSM".

13. On page, 4, section 3 of the new RSM, reference is made to the CPRSA balance being, \$20 million. The \$0.004 RSA recovery component of the tariff cannot reduce this balance to zero by the end of the FTP as required by law (sections 15(2) and 28(2) of the byelaws). In public statements, the Chairman of the PUC stated that the RSA balance was reduced to \$740,000. (See copy of news report attachment D). He also stated that the CPRSA was reduced by corrections arising from variances related to the Value Added of Delivery (VAD) component of the tariff which goes contrary to the concept of the CPRSA, i.e., a rate stabilization account established to manage cost of power only.

14. In the final decision of June 26th, 2007, the PUC had approved a CPRSA balance of \$16,098,216 which is the subject of a challenge by the company. In its 2008 decision, the PUC did not produce any calculations to show how the new balance of the CPRSA was determined. (See Attachment E, Final Decision of June 26th, 2007).

15. Regarding excess cost of power deferred into the CPRSA for the current year 2008, the PUC appears to have arbitrarily disallowed 20% of January and February's deferrals (no mention is made of March's deferrals in the explanations offered). In its justification, the PUC stated that BEL "diverted considerably from its planned energy dispatch profile...". No other details or calculations are provided in support of this decision. This is an unacceptable approach to take regarding the current high cost of power. It appears that the PUC continue to take issue with the price of power from CFE. However, in December 2007 the PUC approved an increase in power from CFE from 15 MW to 20 MW under the terms of the August 2006 contract (See attachment F letter from the PUC).

16. The company carries out dispatch in the most economical manner but giving consideration to the need for maintaining a certain level of water in the Chalillo reservoir to carry through the dry season based on historical average water inflows. Rainfall in the early part of 2008 was much below average since Chalillo was commissioned. As pointed out to the PUC before, not maintaining an adequate level of water in January through March would result in running the Gas Turbine and the Diesels more often in April and May and possibly June and July, which will cost consumers much more. The company sometimes takes more expensive power from CFE to maintain a prudent reservoir level. Moreover, running down the reservoir puts the reliability of the system in jeopardy should there be an extended outage from CFE or the Gas Turbine as has happened in previous years. The PUC has been kept informed of the dispatch methodology and reasons for deviating from the target dispatch on a regular basis and has approved all power purchase agreements for pass through (See attachment F letters from PUC approving PPAs with CFE, BAL and BECOL).

17. In its final decision of June 26th, 2007, the PUC increased the VAD from 16 cents per kWh to 16.8 cents per kWh based on the fact that sales were lower than projected in the FTRP. Sales in 2007 were also lower than that projected in the FTRP. However, the PUC has now reduced the VAD to 13 cents per kWh and did not demonstrate any calculations in its 2008 decision to support this.

18. The PUC has also stated that it has disallowed all previous Hurricane Cost Rate Stabilization Account (HCRSA) charges to customers. This arbitrarily reverses a previous decision by the PUC when it approved the establishment of the HCRSA in 2002 and the subsequent recoveries and balances in the account each year thereafter up until last year's decision. In relation to calculations supporting the PUC's initial tariff decision, it must be noted that not until after repeated requests for this support did the PUC provide a narrative explanation of their calculations on Friday May 9 at 4 p.m., fully one week after their initial decision and one working day before the deadline for objections. This response level is not conducive of a proper regulatory environment. Additionally, during the current ARP the PUC is jeopardizing the financial stability of the utility when it arbitrarily changes its past decisions on which the utility based its financial operations and reported its audited results.
19. After repeated requests, the PUC finally provided a draft and incomplete narrative explanation of their calculations on Thursday May 8th, showing that some of the calculations were incomplete. An updated report was received on Friday May 9, fully one week after their initial decision and one working day before the deadline for objections. The calculations in the final report do not support the initial decision. During the process, the PUC kept requesting information for past years that had already been provided in the ARPs for those years. These actions and lack of organization constitutes a very difficult and unreliable regulatory environment and undermines the credibility of the 2008 decision. At no time did BEL unduly delay the delivery of information to the PUC. In fact, a number of information requests from the PUC were submitted at the last moment and as noted, each year the PUC receives a significant amount of information for that year that they could have readily accessed.
20. On page 7, the fifth paragraph of the introduction to the new 2008 RSM, the PUC states that the RSM can be amended from time to time over the FTP. This does not support a stable and fair regulatory and financial environment for the utility and will only serve to discourage investments in the industry.

21. As noted previously, the PUC has changed the regulatory rules in the middle of an ARP and during an FTP. The changes result in negative financial repercussions on the utility which had been operating and reporting its financial results on a different set of rules. An example of this can be seen in section 59 where the PUC now disallows work-in-progress as a regulated asset value (RAV) and therefore disallows a return on this asset that the company has obtained debt financing and shareholder funds to finance. A utility cannot operate in such an environment which would then result in insufficient returns to the utility to finance work in progress. Additionally the PUC introduces new terms and parameters such as "working RAV" and investments "commissioned and in service" in the new RSM that further limits the level of RAV that can earn a return exacerbating the utility's financial position. The PUC then applies these new rules retroactively.

22. In sections 73 and 74 of the new RSM the PUC now requires that the variance in actual depreciation expense over forecast depreciation expense be adjusted for annually in the next ATP. In the previous RSM which formed the basis of previous rate decisions, the depreciation variance was to be computed only for each 4 year FTP and adjusted for in the first ATP of the next FTP. The principle behind the latter approach was that in the industry, capital expenditures (capex) form a significant part of operations and therefore the utility would need a window in which to properly plan and execute its capex program which then drives depreciation expense. Annual adjustments for depreciation expense variance do not take into consideration external uncontrollable factors that may force a utility to amend its capex program one way or the other. Additionally, depreciation on existing assets ("D_exist" as the PUC calls it) are not taken into consideration in determining the depreciation variance. Furthermore this major retroactive adjustment to the RSM renders invalid the financial results of operations of the Company for the past years in the FTP that the PUC had already reviewed and accepted.

23. In section 99, one of the VAD components is depreciation expense, "D cs" as the PUC calls it, and it appears to exclude depreciation on existing assets as referred to by the PUC as "D exist". This would make the calculation of the VAD incomplete.

24. In section 112 of the new RSM, the delta ROR is not defined anywhere else in the document. Additionally, the comment in this section in bold allows the PUC to set any component of VAD on an annual basis which in effect negates the need for an FTRP that employs a longer period for review of the actual 4 year historical operating performance of the utility in the previous FTP which should then used as a basis to forecast VAD over the next FTP. This is an unstable and unworkable regulatory and financial environment for an investor or financier and is unreasonable.

25. Section 114 needs clarification. What is meant by "Any AC that is not accomplished in any ARP,..."?

26. Section 120 notes that the utility is to further justify significant investment that are individually or in the aggregate for the year in excess of \$250,000 and \$1,000,000, respectively. There is no reference to a timeframe for the PUC to evaluate the investment and provide feedback to the utility. The Company annually submits to the PUC for approval its capital expenditures program but has not received a response. Undue delays in investment decisions will lead to negative impacts on quality of service standards. Some of the targets that the PUC has set for the Utility require the company to make substantial capital investments. Capital expenditures are also required to improve productivity and reduce operational expenses. It is not fair for the PUC to handcuff the company in its capital program then penalize the company for not meeting targets. At any rate, requiring individual approval for these levels of capex will be bureaucratic and unworkable.

27. Section 123 (f) now requires the utility to pay interest on consumer deposits. The utility notes that interest on overdue balances from customers is not charged. This is patently unfair to the utility and to the good paying customers.

28. The PUC continues to insist that the Mollejon Transmission Line is not a regulated asset value on which the Utility is to earn a return despite the PUC being a party to agreements that resulted in BEL paying for the line via a loan with Belize Electric Company Limited (BECOL). BEL

reiterates its position that in the amendments to the Power Purchase Agreement between BECOL and BEL and the Transmission Facility Agreement between the Government of Belize, BECOL and BEL, BEL agreed to pay for the transmission line separately from the price it paid for power and in return, BECOL modified the PPA to exclude capacity charge in addition to other commitments (see copy of agreement attachment G). The PUC and the Government are obligated to honor their commitments and allow the company to earn a fair return on this asset to be able to meet its financial commitments.

3.4 Independent Expert

The Commission received one written objection to the Initial Decision, and in accordance with Byelaw 31, appointed an Independent Expert, Dr. Jonathan A. Lesser, to review the regulated values, mean electricity rate, tariffs, rates, charges and fees. Dr. Lesser's report, issued on June 11, 2008, can be accessed on the Commission's website "www.puc.bz". Selected segments from the "Findings and Recommendations" of Dr Lesser's report are shown below:

The Cost of Power (COP)

Owing to the country's dependence on power from CFE, and because the contract price for that power is based on an index of fossil fuel prices, BEL has clearly experienced an increase in its COP. Moreover, the cost of running the diesel generators owned by BEL has also increased significantly. In its Initial Decision, the PUC set the COP to BZ\$0.307. The basis for this price was a combination of actual power costs during the first few months of calendar year 2008 and the forecast of power costs for the remainder of the year. The PUC stated in its 2008 Decision Summary that

BEL did not provide any objections to setting the COP at the PUC's recommended value. I independently calculated the COP for the 2008 ATP based on data provided to me by the PUC. The value I estimated is \$0.298/kWh. Although I understand the PUC's concern over growth in the CPRSA account, *Good Utility Practice* suggests that the actual projected COP be used. Therefore, I recommend the COP be set to \$0.298/kWh.

Operational Expenditures (OPEX)

According to the 2008 Decision Summary, the PUC increased the Target OPEX higher than the previous target value. The PUC set the 2008 OPEX value to \$19,922,000. There were no objections from BEL. Therefore, I recommend adoption of the PUC's recommended Target OPEX for the 2008 ARP.

Regulated Asset Value (RAV)

RAV represents the undepreciated amount of invested capital. In this ARP, there is a dispute between the PUC and BEL as to what is the correct RAV. Specifically, the PUC reduced the proposed RAV value by subtracting out: (1) the undepreciated value of the Mollejon transmission line; (2) other contributed capital; (3) construction work in progress (CWIP); and two-thirds (2/3) of the value of assets put into service during the calendar year. The RAV calculation is not clear as to the treatment of working capital, which is commonly included in rate base. Compounding these disputes, the PUC's methodology to calculate the projected RAV values is not straightforward. By clarifying the methodology, the PUC will enable all parties to interpret its methodology more accurately.

As I understand the PUC's process, the initial 2008 RAV value was derived from the RAV value at the end of calendar year (CY) 2007 by projecting new capital additions and subtracting out forecast depreciation for CY 2008. Depreciation was estimated for CY 2009 using the same process.

Treatment of Construction Work in Progress (CWIP)

The treatment of CWIP differs across different regulatory jurisdictions. Some regulators permit the inclusion of CWIP into rate base; whilst others do not. Moreover, the treatment of CWIP has changed over time in response to different circumstances. Typically, regulators are reluctant to include CWIP in rate base, because the assets are, by definition, not used and useful whilst under construction. However, in the U.S., different states have taken different approaches depending on the anticipated time before the assets would be placed in service, as well as the magnitude of AFUDC balances created as a result of construction. For example, in a 1991 case, the West Virginia Public Service Commission allowed Monogahela Power to place CWIP expenditures associated with emissions control equipment required under the U.S. Clean Air Act Amendments of 1990 into rate base, while admitting that doing so was a "significant departure from normal ratemaking procedure."

Owing to the lack of uniform treatment of CWIP by regulators in the US and the standard practice in the region, the PUC's exclusion of CWIP from RAV appears reasonable.

Exclusion of Contributed Capital

The PUC has excluded just under \$22.3 million in contributed capital from the RAV estimate. It is my understanding that this figure refers to capital investments that are funded by the Government that are used to improve electric service. As such, I believe it is reasonable to exclude those investments from RAV for purposes of determining BEL's return on investment (TOR). As stated by Goodman,

donated and other cost-free capital is generally excluded from the computation of the fair rate of return. It may be deducted from rate base, consistent with the terms of the donation.

Treatment of the Mollejon Transmission Line Investment

Based on my discussions with PUC and BEL, there is significant disagreement as to whether the cost of the Mollejon Transmission line belongs in RAV. These disagreements appear to stem from how the transmission line asset was transferred to BEL from BECOL, and how the initial power purchase agreement between BECOL and BEL was modified.

On 19 April 1991, BEL, which was then a government-owned entity known as the Belize Electric Board (BEB), and the Government of Belize signed an agreement (known as the Purchase Power Agreement) with Dominion Energy, Inc. and International Energy Equities, Inc. ("Dominion") to develop a 20 MW run-of-river hydroelectric facility on the Macal river at its confluence with Mollejon Creek, in Cayo District, Belize. Additionally, Dominion agreed to build a 139 kilometer 115kv transmission line from the project to the switchyard in Ladyville. The cost of the transmission line was estimated to be about US\$16 million. To recover the costs of the entire project, BEB agreed to a take-or-pay agreement whereby it agreed to purchase a minimum of 120 GWH per year.

Without upstream storage, however, the Mollejon dam could not generate anywhere close to the 120 GWh envisaged under the take-or-pay agreement. On 18 December 1996, only six months after the plant began commercial operation, a Second Master Agreement (SMA), amending the FMA was signed by the parties. Under the SMA, the take-or-pay agreement was modified. First,

the take-or-pay quantity was reduced from 120 GWh to 85 GWh. Second, the SMA incorporated a capacity charge, the amount of which depended on actual generation at the hydro facility. Specifically, the capacity charge would be \$0, if the facility generated 85 GWh or more, and \$0.0875 times the difference between actual production and 85 GWh, if production fell below 85 GWh. Additionally, the \$0.0875 value was to be increased each year by 1.5%. On 21 November 2001, the Third Master Agreement (TMA) was signed. The TMA eliminated the capacity charge that had been added in the SMA.

In 1999, the Mollejon transmission line was "sold" to BEL for US\$1. However, the undepreciated cost of the line has remained on BECOL's books. BEL insists that, in exchange for eliminating the capacity payment, BECOL required BEL to pay back the unamortized cost of the line. There is also an Agreement, dated 21 November 2001, entitled the "Mollejon Transmission Agreement," stating that BEL will pay BECOL the unamortized portion of the transmission line cost, US\$14,896,212.21, and the interest rate for such payments shall be 10%.

The original transfer of the Mollejon Line to BEL for US\$1 is a form of "contributed capital." As discussed previously in Section V.2(b)(2), Goodman states that cost-free capital is generally excluded from rate base for purposes of computing total returns. Similarly, Hanhl note also that U.S. Financial Accounting Standards Board (FASB) Statement No. 116 sets out accounting treatment for contributed capital, stating that a capital asset account would be debited for the fair market value of the asset, and an account with a name such as "contributed capital" would be credited for the fair market value of the asset

The key regulatory question, therefore, is whether eliminating the capacity charge associated with the Purchase Power Agreement in exchange for eliminating the capacity payment that was required under the SMA meant that the undepreciated value of the line should have been added to rate base. I conclude it should not be.

In substance, elimination of the capacity payment in exchange for a stream of payments on the transmission line does not represent acquisition of a capital asset, because the actual asset transaction – the sale of the line to BEL for US\$1 – took place earlier. Rather, the capacity charge on the PPA was simply being paid upfront in advance in full, with BEL choosing to pay over time by taking on the wholesale supplier's liability. Therefore, it appears to me that the payments (other than the principal component) constitute interest expense to the utility, just as with any other loan.

Adjustments to the Rate of Return

One of the most basic tenets of utility regulation is that a utility is entitled to earn a fair and compensatory rate of return on its capital investment. In setting an allowed ROR for a utility, regulators need to account for the financial condition of the utility, its capital structure, its cost of debt and, most difficult of all, an appropriate allowed return on equity. These factors are, in fact, noted in the 2008 RSM. As Justice Douglas of the U.S. Supreme Court stated over 60 years ago,

From the investor of company point of view, it is important that there be enough revenue not only for operating expenses but also for capital costs of the business. ... By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

Equity investors have a junior claim to a firm's assets to that of bond holders. In other words, if a firm goes bankrupt, bond holders are paid before equity holders. As such, equity holders face greater financial risk than bond holders. This means that equity holders will demand a higher expected return on their investment than bond holders. Based on data I received from BEL, the company's average cost of debt is approximately 10%. Moreover, the risk-free rate for debt issued by the Government of Belize is estimated by the International Monetary Fund to have a market interest rate of over 9%. Given that the risk-free rate for bonds issued by the Government of Belize have a market interest rate of over 9%, as indicated by the IMF, setting the ROR for BEL at 8.5% does not allow BEL the opportunity to recover their financing costs, not even if the company were 100% leveraged with a loan from the Government of Belize at the risk-free rate. A ROR of 8.5% will clearly not "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital."

The PUC's action is also inconsistent with respect to the 2008 RSM, which the PUC itself issued on the same day as issuing the Initial Decision. The 2008 RSM maintained the target ROR of 12%, as well as maintained the existing lower and upper ROR bounds of 10% and 15%, respectively. As such, the PUC's decision to reduce the ROR to 8.5% obviously sets the target below the lower band of its own RSM.

The reason given by the PUC for reducing the ROR is not well substantiated. The PUC stated, "Given the current economic conditions, the PUC has decided that a ROR of 8.5% of the RAV translates to a reasonable return on investment."

That is incorrect from an economic point of view: the country's current economic conditions do not translate into lower interest rates or lower cost of capital. Rather, they likely translate into a higher cost of capital because of investor perception of greater country risk.

I therefore recommend that the ROR be set to 12% for the 2008 ARP.

CPRSA and HCRSA Values

I next turn to the PUC's treatment of the CPRSA and HCRSA account values. BEL objects to the PUC's adjustments to the CPRSA account. The PUC reduced the CPRSA in four ways: (1) disallowing 80% of BEL's actual COP for the months of January and February 2008, claiming that BEL did not dispatch sufficient hydro resources and drawing down the Chalillo Reservoir too little; (2) correcting for differences between projected and actual depreciation for the years 2005 through 2007; (3) correcting for actual v. projected TOR; and (4) eliminating all previous balances in the HCRSA account, based on BEL's requirement to self-insure against hurricane damages. Together, the PUC's reductions in the CPRSA reduced that account by almost \$28 million, from a balance of \$18,959 at the end of CY 2007 to -\$8,982., as shown in Table V-3. Using this negative starting value for the CPRSA the forecast COP over the ARP 2008 period, and the requirement that the CPRSA account be zeroed out prior to the start of the next FTRP in July 2009, the PUC recommended a CPRSA value of \$0.004/kWh.

Disallowance of Actual COP

In the 2008 Decision Summary, the PUC stated that "BEL diverted considerably from its planned energy dispatch profile for the 1st Quarter of 2008. BEL objected, stating that the PUC provided no evidence whatsoever of this.

To investigate this issue, I first discussed it with BEL. Specifically, I examined the "rule curve" used by BEL to draw down the Chalillo Reservoir. In essence, a rule curve provides a periodic (in this case annual) guideline for drawing down a reservoir so that the reservoir will be available for generation during times when electricity is most expensive and to ensure that the reservoir will refill. Such rule curves are common for most hydroelectric systems.

The PUC indicated to me that the draw downs were reasonable and that BEL clearly followed the rule curve. Since there is agreement that BEL did, in fact, dispatch the reservoir appropriately, there is no reasonable explanation for disallowing 80% of BEL's actual costs. I am not aware, at this time, of other evidence that justifies such disallowance. Therefore, if the PUC wishes to disallow BEL's costs in this manner, it needs to provide evidence to justify that

decision, specifically evidence with regard to the "considerable" diversion from BEL's planned energy dispatch profile. Since no such evidence was presented to me, I recommend that the PUC's disallowances be excluded from the CPRSA reduction.

Reduction in Depreciation Expenses

Under the 2008 RSM, the PUC can apply the differences between projected and allowed depreciation to any cost component in the next ATP or FTP. This is a change from the previous RSM, under which these differences would be accumulated and applied to the first ATP of the next FTP. BEL notes that, in adopting the 2008 RSM approach, the company's financial statements for previous years are no longer correct.

The PUC's adoption of the 2008 RSM one month after BEL had already filed its Tariff Application, and implementation of rules that retroactively adjust depreciation expenses for the last three years that reduce the CPRSA as a result, do not comport to *Good Utility Practice*. The new regulations allowing the PUC to apply to depreciation adjustment to any account it so chooses in the next ATP increases regulatory uncertainty and may adversely affect BEL's financial stability.

The magnitude of the corrections is also troubling and I do not understand why BEL did not inform the PUC previously of the large and increasing disparity between forecast and actual depreciation expenses. Moreover, delaying the adjustments until the 2009 FTP would exacerbate the adjustments necessary at that time. Although I am tempted to recommend that the PUC not apply the retroactive depreciation adjustments to the CPRSA, delaying those adjustments will create an even larger problem. A potential solution would be to develop a mechanism to recover the cost differences over a longer time period, but this would violate the 2008 RSM (and the 2005 RSM). This is one more indication to me that an entirely new rate methodology is needed.

Reduction in Returns

As with depreciation expenses, the PUC has applied corrections for BEL's TOR to the CPRSA account, as allowed under the 2008 RSM. The reduction reflects the lower allowed RAV for BEL. And, as with the depreciation expense adjustment, I do not believe that the retroactive adjustments comport to *Good Utility Practice*. The magnitude of the corrections is also troubling and I do not understand why BEL did not inform the PUC previously of the large and increasing disparity between forecast and actual allowed returns. Moreover, delaying the adjustments until the 2009 FTP would exacerbate the adjustments

necessary at that time. Although I am tempted to recommend that the PUC not apply the retroactive depreciation adjustments to the CPRSA, delaying those adjustments will create an even larger problem. A potential solution would be to develop a mechanism to recover the cost differences over a longer-time period, but this would violate the 2008 RSM (and the 2005 RSM). This is one more indication to me that an entirely new rate methodology is needed.

HCRSA Disallowance

I understand that the HCRSA account was established to spread out the costs associated with Hurricane damages, thus avoiding the need for large rate increases to compensate BEL for recovery costs. In its Final Decisions for the 2002 ARP, PUC approved an HCRSA value of \$5,814,601. On 16 October 2002, the PUC Chairman sent a letter to BEL requesting that BEL document the damages costs, financing costs, and insurance proceeds. On 24 October 2002, BEL responded with documentation. Over time, the HCRSA balance was reduced. According to the PUC's Final Decision in the 2007 ARP, the HCRSA balance as of 31 December 2006 was \$282,737. Owing to the small remaining balance, the PUC ordered that that balance be transferred to the CPRSA.

My conversations with the PUC indicate that they accept the costs that made up the HCRSA. However, in the 2008 Decision Summary, the PUC now disallows all previous HCRSA charges to consumers owing to a requirement BEL establish a self-insurance scheme, including a \$5 million insurance reserve. BEL, in fact has established such a reserve. In its 2007 Annual Report, BEL's Balance Sheet shows a \$5 million reserve, which would otherwise be recorded as additional retained earnings. The PUC appears to believe that the self-insurance scheme meant setting aside cash for self-insurance and that, because BEL did not do so, BEL's previous HCRSA collections are now unjustifiable. I must disagree.

BEL established a self-insurance approach because the costs of hurricane insurance had become prohibitively expensive or because the insurance companies do not provide coverage. This is typical in many Central American and Caribbean countries, as well as electric utilities in Florida and along the Gulf Coast of the United States. Thus, BEL's ratepayers benefited through not having to pay those insurance premiums. The insurance reserve was established and is shown on the balance sheet under stockholders equity, as is typical of best regulatory practices. For example, a report prepared by the Edison Electric Institute stated that numerous state utility commissions in the U.S. allow regulated electric utilities to establish such reserve accounts.

A storm reserve is an accounting technique that allows utilities to smooth out the earnings impact of major storms. With the exception

of FPL [Florida Power & Light], storm reserves are not funded with cash and therefore do not minimize the cash-flow impact of having to pay the costs of a major storm. When a utility establishes a storm reserve, it credits a fixed amount each year to the reserve through monthly accruals. These monthly accruals are deducted from the current month's earnings even though no actual storm costs are incurred. When a major storm strikes, the storm costs are charged against the balance in the storm reserve account. The reserve, however, provides no cash to pay the actual storm costs. The big benefit of this type of accounting treatment is that it allows utilities to smooth out the earnings impact of major storms. When a big storm strikes, the only charge to earnings the utility incurs is its normal monthly accrual to its storm reserve account, assuming that it has a balance in its storm reserve account.

BEL's stated treatment of its hurricane cost self-insurance programs is consistent with that of other utilities. However, BEL's discussion of the self-insurance scheme in its Annual Reports have changed over time, which I find troubling. The Annual Reports (ARs) for the years 1999 through 2003 refer to "funds set aside in a fixed deposit account to cover the appropriate retained earnings." The 1999 and 2000 ARs refer to specific dollar amounts set aside in fixed deposits against appropriated retained earnings. The other Annual Reports refer only to the appropriation of retained earnings for the insurance reserve. The language in the 1999 through 2003 ARs could be interpreted to mean that cash was, in fact, deposited into a special account. As I am not a forensic accountant, I cannot determine the precise nature of the language in the ARs. Therefore, while I do not recommend accepting the PUC's disallowance of previously incurred hurricane recovery costs, I believe further investigation is warranted.

Recommended CPRSA Balance and Recovery Rate

Table V-4 summarizes by recommendations for the adjustments to the CPRSA balance. Again, I am recommending that there be no disallowance of power costs incurred by BEL for the months of January and February 2008. I also recommend that all of the HCRSA balances not be eliminated. Finally, whilst I believe the subtractions made by the PUC for depreciation and return adjustments are inconsistent with *Good Utility Practice*, I have included those adjustments in my recommended CPRSA balances and recovery rates.

4. Final Decision

The PUC is required to deliver its Final Decision no later than fifteen (15) days after the date of issuance of the independent expert's report; June 26, 2008 is the deadline.

The PUC hereby issues its Final Decision on the regulated values for the ARP regulated parameters.

The PUC also hereby issues its Final Decision on other Issues and Corrections relating to the Cost of Electricity Service during the ATP 2008/2009.

5. Exercise of Regulatory Authority

The PUC with the authority given under the Byelaws read along with other governing legislation hereby renders the following final decisions:

Decision 1 The First Schedule (amended)

The Commission hereby approves the First Schedule (Rate Setting Methodology) (amended). [ANNEX 1]

Comments relating to Decision (1)

The 2005 First Schedule (Rate Setting Methodology (RSM)) approved by the Commission in the Final Decision FTRP 2005 has been the subject of objections by BEL as well as by the Independent Expert for ARP 2007 and the Independent Expert for ARP 2008. It has also been the subject of concern by the Commission, and hence the First Schedule of FTRP 2005 has been amended in this ARP 2008.

The 2005 First Schedule included what appeared to be some revenue capped items relating to the Cost of Power, these items were unfair to Consumers and needed to be amended to be able to function. There were other items apparently intended to provide an incentive to the Utility; these items provided a reward if the Utility was within target, but no penalty if the Utility was outside of target; this structure does not work well as an incentive mechanism.

Another important issue is that the First Schedule states that "The methodology provides for the recovery of the full cost of power, the recovery of changes in cost of power, a fee for capacity support, and a fee for power delivery as is required under the Byelaws". The Cost of Power is a pass-through to consumers with no profit or loss to the Utility, there can be no "revenue cap" on the cost of power.

The First Schedule (RSM) 2005 needed to be amended, but there were delays in amending RSM 2005. In an attempt to amend the RSM 2005, S.I. 141 of 2007 was issued on 22nd December, 2007. S.I. 141 was repealed in late March of 2008.

Given that the First Schedule (RSM) was deemed unfair and S.I. 141 of 2007 was repealed, there remained no other course of action for the Commission but to exert some reasonable effort to make workable amendments to the First Schedule (RSM) 2005, which is available for viewing in the Electricity Sector Publications as Amendment First Schedule (RSM) on the PUC website: www.puc.bz

Decision 2 Regulated Asset Value

The Commission hereby approves the following values for BEL's RAV: a) for the year 2005 the approved RAV is \$194,122,000; b) for the year 2006 the approved RAV is \$ 207,885,000; c) for the year 2007 the approved RAV is \$ 231,954,000; for the year 2008 the approved RAV is \$ 248,379,000 and for 2009 the approved RAV is \$281,819,000. [Annex 2]

Comments relating to Decision (2)

BEL's Regulated Asset Value that provides service to Consumers during the current year is now referred to as the "Working RAV", or simply RAV. The Commission has reviewed and adjusted the RAV for the years 2005, 2006 and 2007. The Commission undertook the review and adjustment of the RAV to ensure that Consumers paid a return and depreciation (capital consumption cost) only on those of BEL's capital assets that are of benefit to Consumers, were not Contributed Capital, and were commissioned and in service during the respective years.

Decision 3 Corrections

In the process of reviewing the objections of the Utility and the finding and recommendations of the Independent Expert, the Commission observed that there were a few notable issues that deserved attention. Below, the Commission seeks to address corrections which resulted from review of the observed issues.

(3a) Depreciation Correction

The Commission in FTRP 2005 forecasted values of depreciation for the Full Tariff Period (FTP). These values for depreciation were included in the forecast VAD, and the forecast VAD for each calendar year has been employed when assembling the actual Tariff Basket Revenue for the respective calendar year.

The Commission has reviewed the allowed depreciation in VAD and has concluded that the allowed depreciation was in excess of the actual depreciation for the years 2005, 2006 and 2007.

The Commission hereby applies a depreciation correction to recover from the Utility, the variance in forecast depreciation above actual depreciation for the years 2005, 2006 and 2007. [Annex 3a]

The total Depreciation Correction approved by the PUC is \$9,628,000.

(3b) Return Correction

The Commission in FTRP 2005 forecasted values of total return for the FTP. These values for return were included in the forecast VAD, and the forecast VAD for each calendar year has been employed when assembling the actual Tariff Basket Revenue for the respective calendar year.

The Commission has reviewed the allowed return in VAD and has concluded that the allowed return is in excess of the actual return that should have been received by the Utility for the years 2005, 2006 and 2007.

The Commission hereby applies a return correction to recover from the Utility, the variance in forecast return in excess of actual return that should have been received by the Utility for the years 2005, 2006 and 2007. [Annex 3b]

The total Return Correction approved by the PUC is \$14,686,000.

(3c) Disallowance of Hurricane Cost Rate Stabilization Account (HCRSA)

The Commission has concluded that BEL had actual expenditures of \$4,485,413 to implement recovery from hurricanes in c/y 2002 and 2003. The Commission also concluded that the actual expenditures attracted interest charges amounting to \$1,552,664 over the period that BEL was recovering the hurricane expenditures through the HCRSA recovery.

The Commission hereby disallows all previously approved HCRSA related Interest Charges amounting to \$1,552,664, and approves a similar amount as a Correction to be recovered from BEL and refunded to Consumers during the ATP July 01, 2008 to June 30, 2009.

The Commission hereby approves \$4,485,413 in hurricane recovery expenditure, but recognizes the recovery of this amount as a replenishment of the Insurance Reserve Fund.

The Commission requires that BEL, from its own funds, re-establish the \$5,000,000 deposit for the Insurance Reserve Fund and that all interest attracted by the fund be deposited into the account until it reaches a balance of \$7,500,000. The Commission further requires that the Insurance Reserve Fund be established as a Trust to be managed by an independent Trustee to be appointed mutually by BEL and the Commission. The \$5,000,000 shall be deposited into the Insurance Reserve Fund by June 30, 2009.

Comments relating to Decision (3c)

The sequence of events below is intended to provide a management trail leading to the Decision (3c); the events are from BEL's AGM reports, a few additional comments are included.

- a) BEL's 1995 AGM's report it is stated that; "In fiscal 1994, the Company discontinued the insurance coverage of its transmission and distribution assets due to a decline in the availability and a significant increase in the cost of insurance. In fiscal 1995 the Company approved a self insurance scheme for transmission and distribution assets and earmarked \$500,000 to be set aside for this scheme. Retained earnings of the Company have been appropriated for this scheme. Subsequent annual appropriations are planned."
- b) BEL's 1999 AGM's report states that; "The insurance coverage of the Company's transmission and distribution assets was discontinued in FY 1994 due to a limitation in the availability and a significant increase in the cost of this insurance. In FY 1995, the Company approved a self insurance scheme for transmission and distribution assets for a total of \$5,000,000 and earmarked \$500,000 per annum to be set aside for this scheme. Retained earnings of the company have been appropriated for this scheme and funds set aside in a fix deposit account to cover the appropriated retained earnings. As at March 31, 1999 \$695,709 had been set aside in fixed deposits against the \$2,500,000 of appropriated retained earnings. A stand-by credit agreement with one of the companies' major bankers for \$5,000,000 is also in place as a part of this self insurance scheme. Revision of the self insurance scheme is necessary as the Company increases its investment in property, plant and equipment."
- c) BEL's 2000 AGM's report states that; "The insurance coverage of the Company's transmission and distribution assets was discontinued in fiscal 1994 due to a limitation in the availability and a significant increase in the cost of this insurance. In fiscal 1995, the Company approved a self – insurance scheme for transmission and distribution assets for a total of \$5,000,000 and earmarked \$500,000 per annum to be set aside for this scheme. Retained earnings of the company have been appropriated for this scheme and funds set – aside in a fixed deposit account to cover the appropriated retained earnings. As at March 31, 2000, \$2,361,243 had been set aside in fixed deposits against the \$3,000,000 of appropriated retained earnings. A stand – by credit agreement with one of the Company's major bankers of \$5,000,000 is also in place as a part of this self – insurance scheme."

Conclusion The facts demonstrate, in reviewing BEL's AGM reports, that because of the high cost and declining availability of transmission and distributor insurance, BEL's Board of Directors in 1994 give directives to set up a self insurance scheme.

Since actual insurance premiums were being paid prior to setting up of the self-insurance scheme, there can be no doubt that Consumers were paying these premiums in the electricity rates. The self-insurance scheme is not an introduction of new expenditure items, it is a requirement to obtain the insurance at less cost to Consumers, and to keep the money at home until needed to pay for system rehabilitation. The funds approved for the scheme were a substitute for the payment of insurance premiums for BEL's external plant, and were never intended to form a part of BEL's profits. The directive was clear; \$500,000 annually to be set aside and deposited into the bank account. Therefore when Consumers were required to pay out the HCRSA account, this amounted to Consumers paying twice for hurricane rehabilitation.

(3d) Disallowance of Mollejon Transmission Facility Loan Interest

The Commission hereby disallows all interest charges that the Utility paid to BECOL related to the Mollejon Transmission Facility.

The Commission hereby approves an Interest Charge Correction of \$10.34 million to provide for the recovery of interest charges from 2001 to 2004 related to the Mollejon Transmission Facility Loan that was paid out of rates levied on consumers.

Comments relating to Decision (3d)

From 2001 to 2004 the Utility paid interest charges to BECOL amounting to \$10.34 million; and from 2005 to 2006 the Utility paid interest charges to BECOL amounting to \$3.56 million. These interest charges are in connection with the Mollejon Transmission Facility Agreement of November 2001. The Commission has always concluded and now reiterates that the Mollejon Transmission Facility is a form of Contributed Capital, and therefore there can be no interest charges related to the Mollejon Transmission Facility. These interest charges were included in the electricity rates paid by Consumers, and therefore, it is only fair that these interest charges be recovered and refunded to Consumers.

The Mollejon Transmission Facility is further discussed below in decision 11.

Decision 4 Rate of Return (ROR)

The Commission hereby approves a rate of return (ROR) of 10% for ATP July 1, 2008 to June 30, 2009. The approved rate of return is to be applied to BEL's RAV for the purpose of calculating the total return for calendar years 2008 and 2009.

Comments relating to Decision (4)

The First Schedule (Rate Setting Methodology) (amended) provides for the calculation of a total return (TOR) that the Utility will be allowed to earn on the RAV. The total return is to be calculated by applying a rate of return (ROR), to licensee's RAV as follows:

$TOR_t = ROR \cdot RAV_t$ where RAV_t is the working RAV for the current calendar year.

In determining the ROR to be applied to the RAV, the Commission was guided by the following parameters: **a)** a regulated lower limit of 10%, a target of 12% and a regulated upper limit of 15%; **b)** Section 11(1) of the Public Utilities Commission Act which states that "Every rate made, demanded or received by any public utility provider shall be fair and reasonable and in any case shall be in conformity with and shall use the rate setting methodologies specified in any Regulations, By-laws, Orders, directions or other subsidiary legislation or administrative orders made under the Electricity Act"; **c)** The Commission's own assessment of the current economic climate in Belize and worldwide; **d)** BEL's Weighted Average Cost of Capital (WACC) of below 10%.

It is the Commission's assessment that, in balancing the needs of all stakeholders within the three parameters described above, an ROR of 10% is fair and reasonable to all stakeholders.

Decision 5 Value Added of Delivery

The Commission hereby approves a VAD for ATP July 01, 2008 to June 30, 2009 of \$56.917 million.

Comments relating to Decision (5)

In both ARP 2006 and ARP 2007 the Utility exceeded the target value of Opex and offered the Commission no explanation. This reallocates additional costs to Consumers, without reasonable justification. The Commission has increased the target Opex for ARP 2008 and 2009, and in the interest of all stakeholders, requires that the Utility stay within this increased value of target Opex.

Decision 6 Mean Electricity Rate

Decision (6a)

The Commission hereby approves a forecast Tariff Basket Revenue (TBR) for BEL of \$185,367,014 for ATP 2008/09, for expected 420,333,335 kilowatt-hours of electricity sales. The forecast TBR and sales convert to a Mean Electricity Rate (MER) of \$0.441/kWh.

The MER was calculated as follows:

Regulated Parameters		Regulated Values		
		ARP 2007 Final Decision	ARP 2008 Adjustments	ARP 2008 Final Decision 2008/09
Base Unit Cost of Power (sales)	\$/KWh	0.253	+0.059	0.312
Value Added of Delivery	\$/KWh	0.168	-0.033	0.135
CPRSA recovery rate	\$/KWh	0.020	+0.060	0.080
Force Majeure Cost Rate Stabilisation Account Adjustment	\$/KWh	0.000	0.000	0.000
Correction	\$/KWh	0.000	-0.000	-0.086
Mean Electricity Rate	\$/KWh	0.441	0.000	0.441

Decision (6b)

A new Rate Setting Methodology (RSM) shall be implemented for September 1, 2008. The new RSM shall provide for an Automatic Adjustment Mechanism (AAM) to adjust the Cost of Power component of rates on a monthly basis to reflect the true and current price of power.

The RSM shall include an account to track monthly surpluses or deficits in the cost of power, which shall replace the CPRSA.

The Cost of Power component of rates to be charged in the current month shall be forecast and publicized in the previous month, and surpluses or deficits shall be credited or debited to consumer accounts in the following month. Fixed fees for VAD, CPRSA recovery and Corrections shall comprise the remainder of the rates to be charged to consumers over a defined ATP.

The Commission shall make provisions under the new RSM to extend the periods for the recovery of the CPRSA balance and for the application of approved Corrections, should BEL so desire.

Any outstanding balance in the CPRSA that is not sufficiently paid down by the CPRSA recovery rate will be addressed through the AAM.

Comments relating to Decision (6a)

The Base Unit Cost of Power at Consumers meters of 31.2 cents/KWh was derived using a forecast unit cost of power from the producers of 25.92 cents/KWh. This was used in combination with forecast sales of electricity to Consumers of 420,333,335 kilowatt-hours for the period July, 2008 to December, 2008.

The Value Added of Delivery (VAD) unit rate of 13.5 cents/KWh was arrived at using calculations which produced the VAD components for calendar years 2008 and 2009.

The CPRSA unit rate of recovery of 8 cents/KWh is intended to recover by June 30, 2009, from Consumers to the Utility, the expected balance of the CPRSA at June 30, 2008 of \$35,345,964.

The Corrections unit rate of recovery of -8.61 cents/KWh is intended to recover, from the Utility to Consumers, a package of corrections of \$36,199,894.

Comments Relating to Decision (6b)

The Cost of Power Rate Stabilization Account (CPRSA) was initially intended to smoothen rates charged to Consumers against price of power volatility. Under the CPRSA mechanism, Consumers are allowed to pay a fixed reference price for power to the Utility, which sometimes resulted in Consumers paying to the Utility less money for cost of power than what it cost the utility to purchase/produce power, or vice versa.

Any money that the Utility paid out for cost of power in excess of what Consumers paid the Utility was held in the CPRSA. Conversely, surpluses paid by consumers were credited to the CPRSA. Consumers had to pay down any outstanding balances in this account over time, and Consumers also had to pay an interest charge on the CPRSA at 12% per annum.

The Commission has assessed the value of the CPRSA and has concluded that the cost of the CPRSA outweighs its benefits, and the Commission will bring the account to a close. It is expected that Consumers will be required to pay monthly for the full cost of power, since this is a lower cost option than to keep the CPRSA, and will relieve BEL of cash flow pressures as a result of the deferral of excess cost of power expenses.

Decision 7 CPRSA (Cost of Power Rate Stabilization Account)

Decision (7a)

The Commission hereby approves the following CPRSA balances: at December 31, 2007 \$ 18,959,205; forecast to June 30, 2008 \$ 35,345,964; and forecast to June 30, 2009 \$243,481.

Comments relating to Decision (7)

Bylaw 145 of 2005 requires that the CPRSA account be paid down to zero by the end of the FTP, and the Commission has set the CPRSA recovery rate to achieve such requirement. Because the CWP changes over time, the Commission recognizes that there may be a residual balance in the CPRSA at June 30, 2009. It is the Commission's intention to pay out any such residual balance through the AAM in the new RSM.

Decision 8 Electricity Wholesale Power and Sales

The Commission hereby approves an expected production of Wholesale Power of 470,988,127 KWh for the year 2008, and 503,514,368 KWh for the year 2009. The Commission also approves an expected Cost of Wholesale Power (CWP) at the generator for the year 2008 of \$133,892,987, and for the year 2009 of \$142,909,513.

The Commission also approves expected electricity sales to Consumers for the year 2008 of 403,892,987 KWh, and for the year 2009 of 436,759,945 KWh.

Decision 9 Capital Investments 2008 and 2009

The Commission hereby approves allowed capital investments for c/y 2008 at \$25 million, and allowed capital investments for c/y 2009 at \$25 million.

The Commission hereby requires the Utility to submit to the Commission a listing of all capital expenditures in progress and all other capital expenditures that will proceed in year 2008. The Commission also requires the Utility to submit a reasonable explanation of the need for each capital expenditure in year 2008, including the benefits to be received by Consumers from these capital expenditures. The Commission also requires the Utility to submit an explanation of the expected impact of each capital investment that may be delayed.

The Commission hereby requires the Utility to submit to the Commission a listing of all capital expenditures expected to proceed in year 2009. The Commission also requires the Utility to submit a reasonable explanation of the need for each expected capital expenditure in year 2009 including the benefits to be received by Consumers from these capital expenditures. The Commission also requires the Utility to submit an explanation of the expected impact of each capital investment that is now expected to be delayed.

Comments relating to Decision 9

In FTRP 2005 the Commission approved \$152 million for capital investments for the calendar years 2005 to 2009. In a recent review, the Commission was informed that the Utility was now forecasting \$223 million for capital investments for years 2005 to years 2009.

Capital investments have the potential to have an impact on efficiency, electricity rates, as well as on quality of service to Consumers. The Commission requires that capital investments be supported by reasonable explanations as to how consumers will benefit.

Decision 10 Customer Tariffs

The PUC HEREBY DISAPPROVES any changes to the tariffs. The Present tariffs shall remain in effect for the Annual Tariff period July 1, 2008 to June 30, 2009, until otherwise adjusted under the new RSM.

APPROVED TARIFF SCHEDULE FOR JULY 1, 2008 TO JUNE 30, 2009

Customer Class and Consumption	Approved Tariffs
Social Rate Customers	
Minimum Monthly Charge	\$4.00
0 – 50 kWh	\$0.26
Residential Customers	
Minimum Monthly Charge	\$5.00
0 – 50 kWh	\$0.35
51 – 200 kWh	\$0.44
Above 200 kWh	\$0.47
Commercial Customers	
Monthly Service Charge	\$100.00
0 – 10,000 kWh	\$0.45
10,001 – 20,000 kWh	\$0.44
Above 20,000 kWh	\$0.43
Industrial 1 Customers	
Monthly Service Charge	\$100.00
Monthly Demand Charge per kVA	\$35.00
Off Peak Energy Rate per kWh	\$0.33
Peak Energy Rate per kWh	\$0.33
Industrial 2 Customers	

Monthly Service Charge	\$100.00
Monthly Demand Charge per kVA	\$21.00
Off Peak Energy Rate per kWh	\$0.28
Peak Energy Rate per kWh	\$0.28
Street Lights	
Energy Rate per kWh	\$0.55

Decision 11 Mollejon Transmission Facilities

The Commission has always concluded and now reiterates that the Mollejon Transmission Facilities (the Mollejon Transmission Line) is a form of Contributed Capital to BEL.

The Commission concludes that the Mollejon Transmission Line is not in any way a part of the Regulated Asset Value (RAV) of BEL, and that BEL will not receive a return on the Mollejon Transmission Line through electricity rates.

Comments relating to Decision 11

The following sequence of events, extracted from BECOL/BEL Agreements and from BEL AGM report/s, should contribute to a reasonably clear understanding of the decision:

- a) In Article 4.1 of the Franchise Agreement of April 19, 1991, it is stated that on the completion of the Transmission Facility by the Producer (BECOL), the facility would be conveyed to the Electricity Board for 1US dollar.
- b) In Article 9 of the Power Purchase Agreement of April 1991; it is again stated that Transmission Facilities are to be built by the Producer at the Producer's expense, and that "upon completion the Transmission Facilities will be dedicated, transferred and assigned to the Utility for one dollar US."
- c) In Article 2.3 In the Second Master Agreement of December 18, 1996, it is stated that "BECOL conveyed and BEL accepted, all of BECOL's right, title and interest in and to the Transmission Facilities as of April 1, 1996, as contemplated by Article 9 of the Power Purchase Agreement

(PPA) and Section 13.2 of the Franchise Agreement, and as conveyed by the Deed of Assignment and Conveyance dated December 18, 1996 by and between BECOL and BEL.”

- d) In BEL's Annual General Meeting (AGM) report of 1997, note 15 Capital Contributions, it is stated as follows: "During 1997, the Company settled the BECOL dispute (see note 16) and accepted the transmission facility from BECOL connecting the Mollejon hydroelectric plant to the Company's distribution system. The facility was recorded at fair market value (BECOL's cost) with a corresponding capital contribution recorded. A total of \$29,751,632 was recorded." At this juncture the Mollejon Transmission Line is on BEL's books as a Contributed Capital.

BY ORDER OF THE OFFICE

SIGNED THIS 26th DAY OF JUNE 2008



John P. Avery
Chairman